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COMMISSION

REVISED 2010 PEAK DEMAND FORECAST

Commission Report

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Abstract

The report *Revised 2010 Peak Demand Forecast* was prepared to document the methods and assumptions behind the forecast of 2010 peak demand that will be used for the 2010 local area capacity requirements study by the California Independent System Operator.

Keywords: Demand forecast, peak demand, extreme temperature, local capacity requirements

Executive Summary

The electricity demand forecasts adopted by the California Energy Commission (Energy Commission) are key inputs into the analysis necessary to determine resource adequacy requirements in the California Independent System Operator control area. The Energy Commission regularly prepares forecasts of annual peak demand that serve as the control total for the load-serving entities under the jurisdiction of the California Public Utilities Commission. The demand forecasts are also used by the California ISO in its analysis of local area capacity requirements.

The most recent demand forecast was prepared for the *2007 Integrated Energy Policy Report (2007 IEPR).* [1] The Energy Commission plans to use the draft forecast being prepared for the *2009 IEPR*, due April 2009, to establish the 2010 year-ahead system resource adequacy forecasts. The 2010 LCR study, however, requires a demand forecast before that time. The LCR study determines the minimum amount of resources that must be available to the California ISO within each area identified as having local reliability problems. This determines the generation capacity in megawatts that is required to address these problems, and the capacity that is allocated to load-serving entities as part of their year-ahead local resource adequacy requirement. To avoid a large disconnect between the assumptions the California ISO uses to determine local capacity requirements and the forecasts that drive the system capacity requirements, Energy Commission staff evaluated the *2007 IEPR* forecast against current loads and economic projections to assess whether an April 2009 draft forecast is likely to be significantly different from the *2007 IEPR* forecast.

Staff concluded that for the Southern California Edison area, their revised forecast for 2010 is likely to be significantly lower than the current adopted *2007 IEPR* forecast. Staff recommends a reduced forecast for the SCE area with no changes to the forecasts for San Diego Gas & Electric or Pacific Gas and Electric. The revised 1-in-2 forecast for the SCE area in 2010 is 24,152 megawatts (a reduction of 693 megawatts); the revised 1-in-10 forecast is 26,027 megawatts (a reduction of 741 megawatts). This includes revising the forecast of California Department of Water Resources demand to more accurately reflect coincident peak demand and ongoing legal restrictions on pumping. The adopted forecast documented in this report, *Revised 2010 Peak Demand Forecast*, is shown in **Table ES-1**. The revised forecast is intended for near-term purposes only and does not imply any changes to the 2007 IEPR adopted 10-year forecast.

[1] California Energy Commission, 2007, *California Energy Demand 2008-2018: Staff Revised Forecast*, CEC-200-2007-015-SF2.

Table ES- 1: Revised Forecast for SCE Area 2010 Peak Demand (MW)

	2007 IEPR Forecast		Revised Forecast		
	1-in-2	**1-in-10**	**1-in-2**	**1-in-2**	**1-in-10**
Coincident Peak by Utility	**2010**	**2010**	**2009**	**2010**	**2010**
SCE Service Area by Climate Zone:					
Zone 7 (Southern San Joaquin Valley)	1,318	1,417	1,264	1,292	1,387
Zone 8 (Coastal LA Basin)	8,992	9,750	8,787	8,888	9,626
Zone 9 (Inland LA Basin)	4,076	4,412	3,960	4,018	4,344
Zone 10 (Inland Empire)	7,841	8,428	7,464	7,652	8,215
SCE Service Area Total	22,227	24,007	21,476	21,849	23,571
Anaheim Public Utilities Dept.	584	631	572	578	624
Riverside Utilities Dept.	619	669	587	603	651
Vernon Municipal Light Dept.	184	184	182	182	197
Metropolitan Water District	185	185	185	185	185
Other Publicly Owned Utilities	282	305	270	276	298
Pasadena Water and Power Dept.	300	324	300	300	324
Dept of Water Resources - South	463	463	178	178	178
SCE Area Coincident Peak	**24,845**	**26,768**	**23,750**	**24,152**	**26,027**

Source: California Energy Commission

Chapter 1

Study Approach

The two most significant determinants of near-term peak demand forecasts are the level of current weather-adjusted loads and near-term projections of the economic and demographic forecast drivers. To assess the reasonableness of using the *2007 IEPR* load forecast for the 2010 Local Capacity Requirements (LCR) study, staff evaluated the November 2008 economic projections of Economy.com and hourly demand data through summer 2008. This analysis was done for each of the three Transmission Access Charge (TAC) areas contained in the California Independent System Operator (California ISO) Control Area: San Diego Gas & Electric (SDG&E), Pacific Gas and Electric (PG&E), and Southern California Edison (SCE).

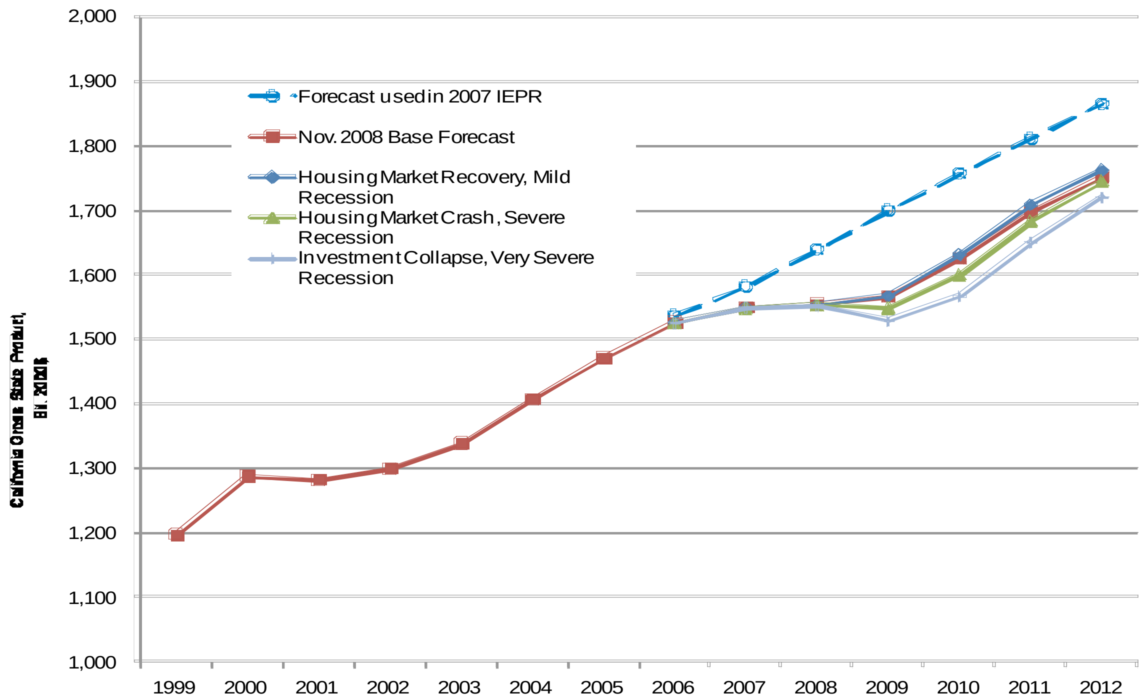
Economic and Demographic Assumptions

In the Energy Commission electricity demand forecasting models, one of the fundamental drivers of the forecast path is population growth. Staff uses the population forecast to project growth in the number of households and additions to commercial floor space in sectors such as schools, hospitals, and retail. The California Department of Finance (DOF) population projections used by staff do not capture the short-term fluctuations in population associated with business cycles, so this driver is relatively stable over time and from forecast to forecast. Since DOF will not be revising its population projections this year, the *2009 IEPR* forecast will use the same long-term population projections, updated by Energy Commission staff for current population estimates.

The near-term economic projections, however, must be different than those developed in 2007 given the current unexpectedly severe economic downturn. The economic forecast drivers, including personal income, employment, and industrial output, contribute to growth in the commercial and industrial sector demand forecasts, and to a lesser extent in the residential sector. Staff uses the economic projections prepared by Economy.com to develop these economic forecast drivers.

Figure 1 compares the projections of California gross state product used for the *2007 IEPR* forecast with the November 2008 Economy.com forecasts. Their base forecast appears to represent a moderate recession; they also provide alternative, more severe outlooks. In all cases, the rate of growth is significantly below that assumed for the *2007 IEPR*, although some degree of rebound is projected by 2010. Economy.com updates its forecast frequently and the final projections used by staff are likely to differ from those in Figure 1**.**

Figure 1: Forecasts of California Gross State Product



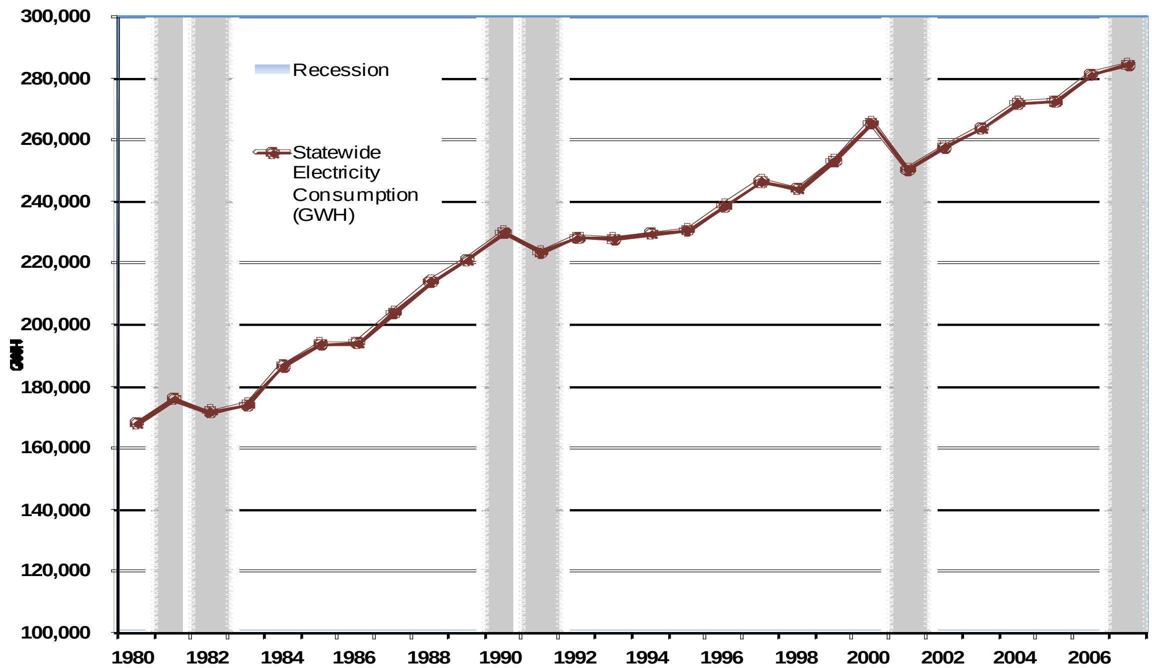
Source: Economy.com, November 2008

These economic projections reflect recent information and analysis about the likely evolution of this business cycle, but forecast errors tend to be higher at times of turning points in these cycles.[2] While this is less of a concern for long-term demand forecasts used for policy and planning, the accuracy of nearer term forecasts is more vulnerable to economic forecast error. Stagnant demand growth during times of recession can quickly be offset when the economy recovers.

Figure 2 shows historical California electricity consumption and years when a recession occurred. Immediately following a recession, annual growth in electricity usage varied from less than 1 percent in the early 1990s to 7 percent in 1984. While forecasters may expect to see flat or declining demand in 2009, the level of demand in 2010 is far less certain. For this reason, staff recommends revising the forecast only for significant differences from the original staff forecast assumptions.

[2] See, for example, Congressional Budget Office, 2007, *CBO's Economic Forecasting Record: 2007 Update*.

Figure 2: California Electricity Consumption and Business Cycles



Source: California Energy Commission

Weather-Adjusted Demand Assessment

Because summer peak demands are highly sensitive to temperature, any evaluation of peak demand trends must account for temperature effects. For this analysis, staff used hourly load data from the California ISO for the TAC areas and for individual load-serving entities (LSEs), and daily temperatures to estimate the relationship between the summer weekday afternoon (1 p.m.-6 p.m.) peak and temperatures. Summer is defined as the period from June 15 to September 15. The temperature variable for each utility is a weighted average of temperatures from a set of weather stations that are representative of the climate in that utility's region. The weights are based on the estimated number of residential air conditioning units in each utility climate zone.

The staff method for assessing demand-temperature response is documented in a previous report;[3] however, two separate weather variables are usually calculated. The first is a weighted average of maximum temperatures on three days. The weighting consists of 60 percent of the current day's maximum temperature, 30 percent of the previous day's maximum, and 10 percent of the second previous day's maximum. The lag is used to account for heat build-up over a three-day period. For the PG&E and SCE areas, the "1-in-2" or normal peak temperature is the median annual maximum temperature from 1950 to 2008. The period used for the SDG&E

[3] California Energy Commission, June 2007, *Staff Forecast of 2008 Peak Demand*, CEC-400-2007-006-SF.

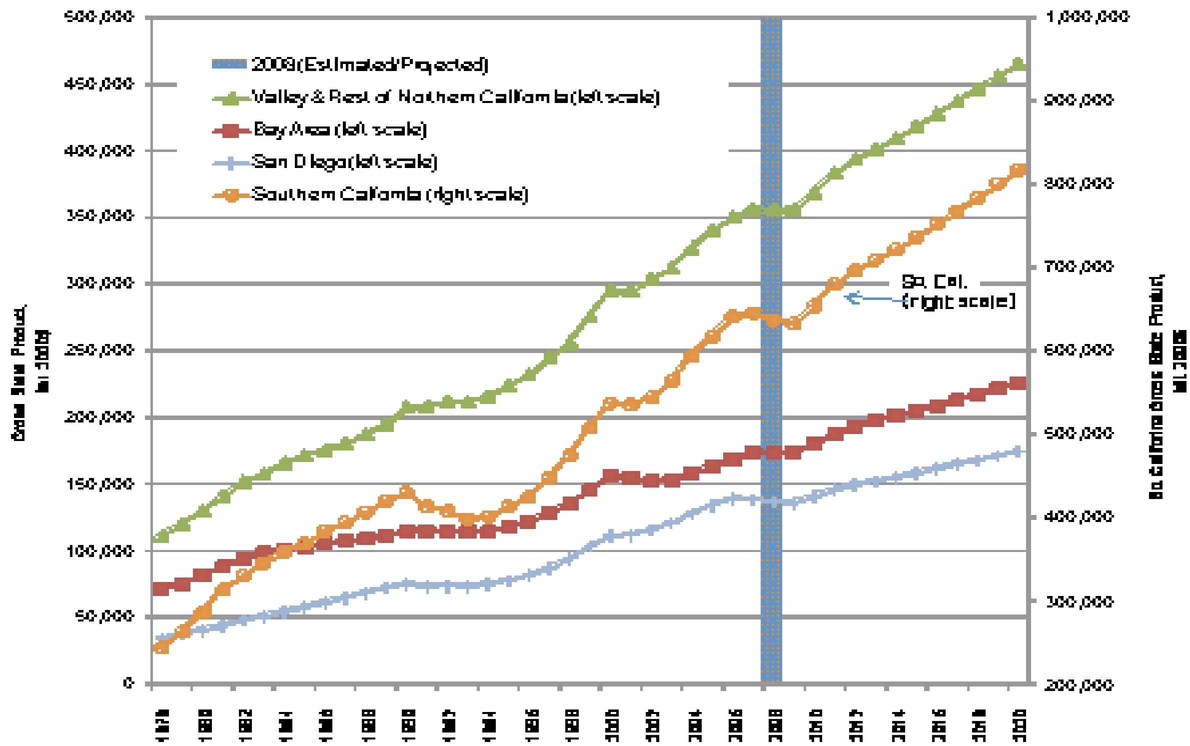
planning area is limited to 1979-2007 because daily weather data are not continuously available before 1979. The daily temperature spread, or diurnal variation, is the second temperature variable. This variable is the daily maximum temperature minus the daily minimum temperature. It captures the effects of the degree of nighttime cooling and serves as a proxy measure of daily humidity.

Chapter 2

Forecast Assessment by Region

To forecast demand in each utility area, staff sums the county-level economic and demographic projections by utility climate zone. **Figure 3** shows the November 2008 Economy.com base forecast aggregated to regions that approximate the utility forecast areas. The Southern California region, served by SCE and numerous publicly owned utilities, is expected to suffer the largest effects of the economic downturn, with gross state product decreasing in 2008 and 2009. The PG&E and SDG&E area forecasts indicate only a slight decline in 2009. Given these projected rates of growth and current weather-adjusted loads, staff assessed whether the forecast for each area still appears reasonable.

Figure 3: Forecast of California Gross State Product by Region



Source: Economy.com, November 2008

Southern California Edison Area

The SCE TAC area includes the SCE service area, California Department of Water Resources (CDWR) Southern California pumping loads, Anaheim, Riverside, and other public utilities. The *2007 IEPR* forecast growth rate averages 1.7 percent annually. **Table 1** shows the forecast by LSE.

Table 1: *2007 IEPR* Forecast for SCE Area 2007-2010 1-in-2 Peak Demand (MW)

LSE	2007	2008	2009	2010
SCE Service Area by Climate zone:				
Zone 7 (Southern San Joaquin Valley)	1,239	1,264	1,292	1,318
Zone 8 (Coastal LA Basin)	8,687	8,787	8,888	8,992
Zone 9 (Inland LA Basin)	3,903	3,960	4,018	4,076
Zone 10 (Inland Empire)	7,280	7,464	7,652	7,841
SCE Service Area Total	21,109	21,476	21,849	22,227
Anaheim Public Utilities Dept.	566	572	578	584
Riverside Utilities Dept	572	587	603	619
Vernon Municipal Light Dept	180	182	182	184
Metropolitan Water District	184	185	185	185
Other Publicly Owned Utilities	264	270	276	282
Pasadena Water and Power Dept	299	300	300	300
Dept of Water Resources - South	463	463	463	463
SCE TAC Area Coincident Peak	**23,638**	**24,035**	**24,438**	**24,845**

Source: California Energy Commission

Figure 4 shows SCE TAC area weekday summer peak demands and temperatures from 2006 to 2008. While the mild temperatures of summer 2008 make a weather-adjusted peak difficult to estimate, the data strongly indicate a lack of load growth from 2007 to summer 2008. For a given temperature, daily maximum demand in 2008 was generally the same as or lower than in 2007. A regression estimate of weather-adjusted demand from 2008 loads and temperatures implies that peak demand has dropped. However, with only one data point over 100 degrees Fahrenheit (F°), and few over 95 F°, the data do not support a reliable estimate of what demand would have been at the 1-in-2 temperatures of 101.5 F°.

Using staff's weather adjusted estimate for 2007 of 23,300 MW as the estimate of current SCE demand,[4] demand would have to grow by 6.6 percent to reach the *2007 IEPR* 2010 demand forecast, much higher than the forecasted growth in economic output of 2.7 percent. While the historical patterns of post-recession demand growth suggest this magnitude of increase is possible, it is toward the extreme end of the distribution of possible outcomes. Staff recommends reducing the forecast to 2009 levels, which assumes cumulative growth of 3.7 percent, more typical of recovery periods.

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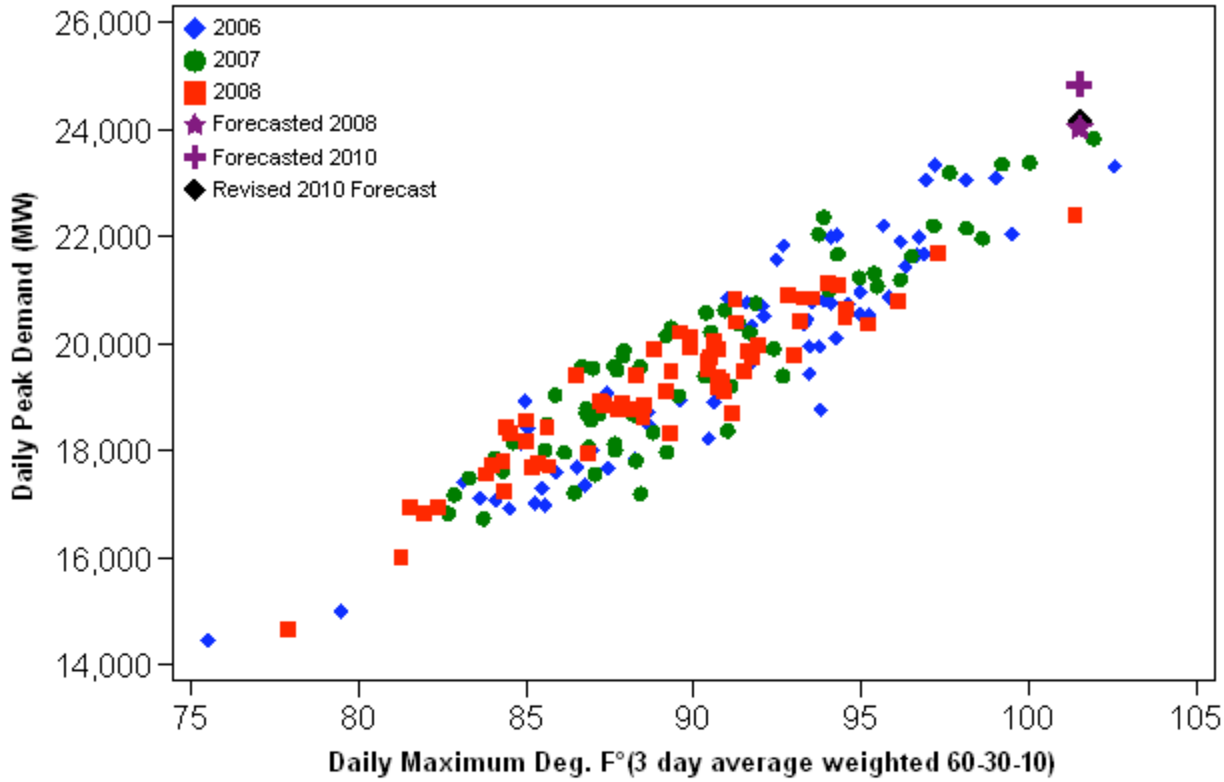
[4] http://www.energy.ca.gov/2008_summer_outlook/documents/2008-01-16_workshop/presentations/Marshall_Lynn_Demand_forecast_and_Preliminary_Summer_2007_Temperature-Load_Assessment.PDF

Figure 4: SCE TAC Area Daily Peak Demand Versus Temperature

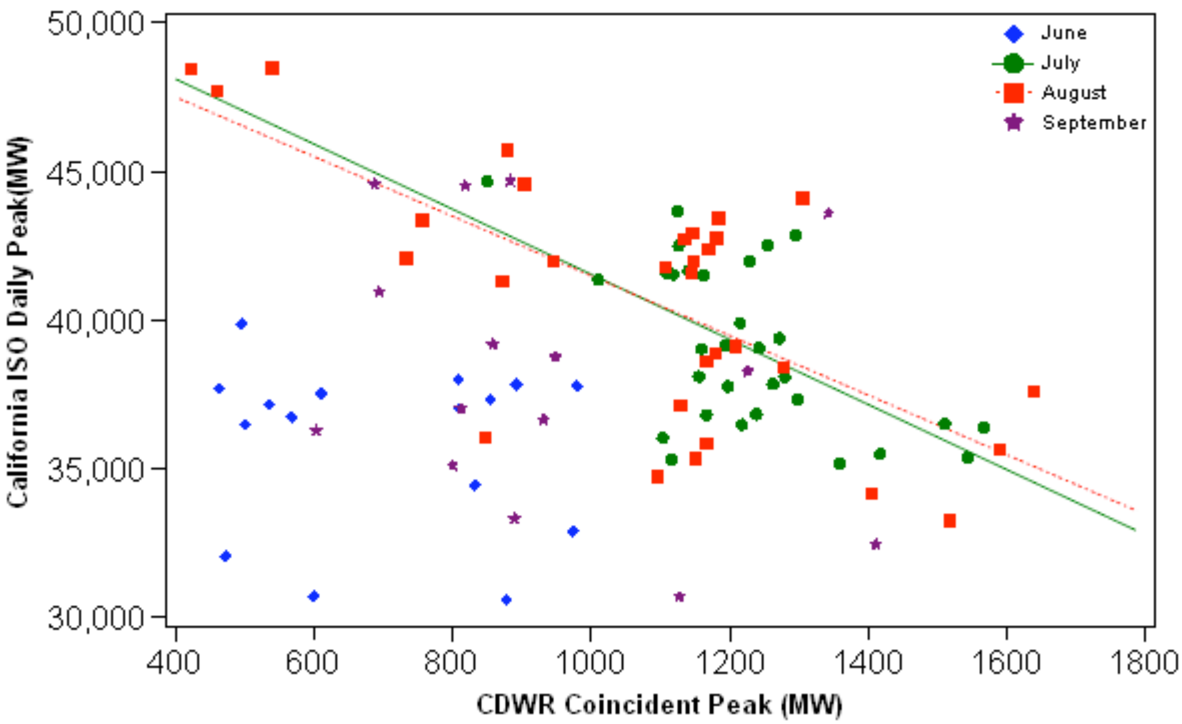


Source: California Energy Commission

CDWR South

CDWR South loads include pumping loads from CDWR units in the SCE TAC area. The Energy Commission's standard method of calculating summer peak period demand for CDWR has been to calculate the average hourly demand over all summer weekdays between 1 p.m. and 6 p.m. This is an appropriate method for calculating the noncoincident summer peak period demand, but will overstate CDWR's contribution to the annual system peak. As shown in **Figure 5**, CDWR coincident peak demand tends to be negatively correlated with system peak; particularly in July and August, pumping load is lowest during times of greatest demand. On Figure 5, the trend lines for July and August indicate the degree of relationship in 2007.

Figure 5: CDWR 2007 Summer Weekday Coincident Peak



Source: California Energy Commission

To project demand, the *2007 IEPR* forecast used load data from years with average hydrologic conditions. A new issue in forecasting CDWR demands is the interaction of hydrologic conditions and legal restrictions on pumping. Beginning in December 2007, CDWR operations were constrained by a federal court ruling effectively ordering the agency to reduce water exports from the Sacramento-San Joaquin River to protect the threatened Delta smelt. In December 2008, the U.S. Fish and Wildlife Service issued a biological opinion that essentially recommends continuing those reductions in exports. This operational constraint appears likely to continue through 2010.[5] Staff used 2007 loads assuming the dry (but not critical, and with high initial storage) water conditions serve as a proxy for these pumping restrictions.[6] The revised forecast of 178 MW, shown in **Table ES-1** and **Table 4**, is calculated as the median CDWR coincident peak on the top three system peak days from 2007.

[5] http://www.fws.gov/sacramento/es/documents/SWP-CVP_OPs_BO_12-15_final_OCR.pdf

[6] http://cdec.water.ca.gov/cgi-progs/iodir/wsihist

San Diego Gas & Electric Area

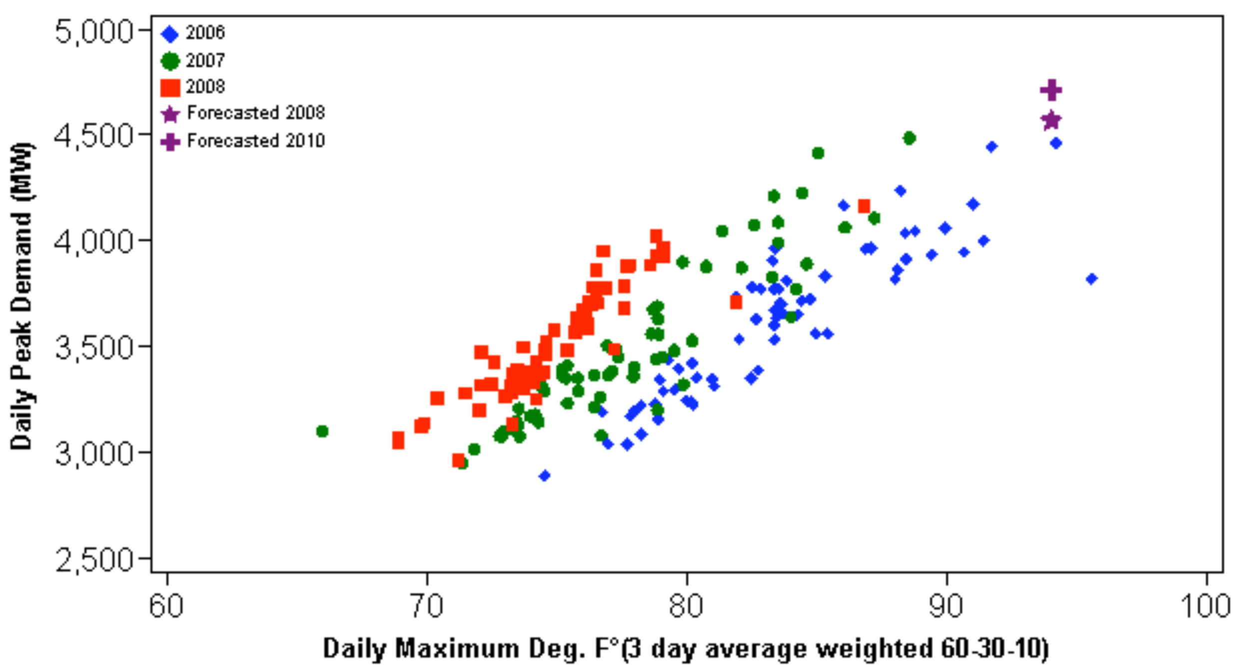
A distinguishing characteristic of the SDG&E area is the small proportion of its load in the industrial sector. In SCE and PG&E, the industrial sector is about 15 percent of total demand, while in SDG&E the share is 7 percent. Economic cycles therefore may have less effect on SDG&E peak demand. The *2007 IEPR* forecast, shown in Table 2, projected average annual growth rate of 1.5 percent from 2007 to 2010. The temperature data shown in **Figure 6** is preliminary, but as with SCE, the low temperatures of summer 2008 make it to difficult to assess high temperature demand responsiveness. However, the lower temperatures 2007 and 2008 daily peaks indicate continuing load growth consistent with the current forecast. The *2007 IEPR* forecast assumes demand in the SDG&E area grows slightly more than 3 percent cumulatively from 2008 to 2010, slightly lower than the current forecasted growth in output of 3.3 percent. Therefore, staff recommends no change to the SDG&E area forecast.

Table 2: *2007 IEPR* Forecast for SDG&E Area 2007-2010 (MW)

1-in-2 Peak Demand				1-in-10
2007	2008	2009	2010	2010
4,506	4,568	4,641	4,712	5,127

Source: California Energy Commission

Figure 6: SDG&E TAC Area Daily Peak Demand Versus Temperature



Source: California Energy Commission

Pacific Gas and Electric Area

The PG&E TAC area includes the PG&E service area, CDWR Northern California pumping loads, Silicon Valley Power, and other public utilities. The *2007 IEPR* forecast growth rate is 1.3 percent annually, lower than the SCE or SDG&E areas because of lower population projections. **Table 3** shows the forecast by LSE.

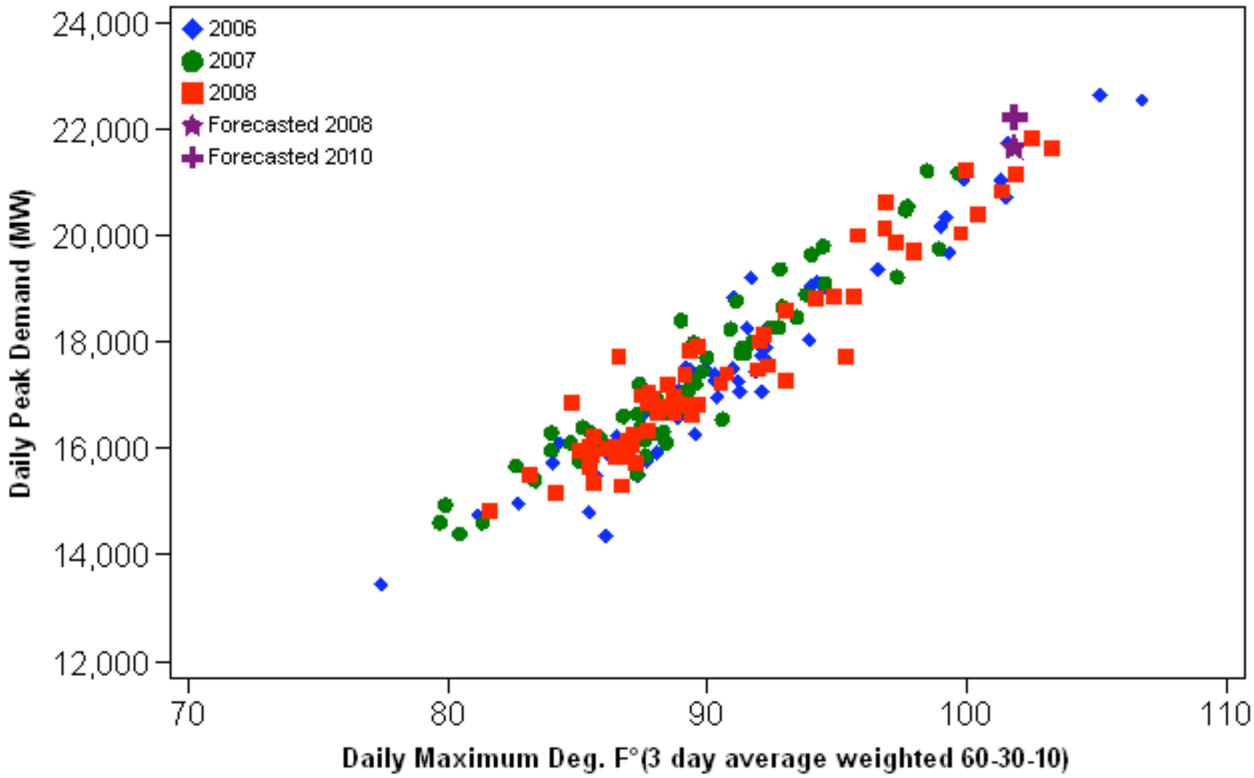
Table 3: *2007 IEPR* Forecast for PG&E Area 2010 Peak Demand (MW)

	***2007 IEPR* Forecast**				
	1-in-2				**1-in-10**
PG&E Service Area by Climate zone:	**2007**	**2008**	**2009**	**2010**	**2010**
Zone 1 (North Coast and Mountain)	774	782	794	805	835
Zone 2 (Sacramento Region)	2,141	2,187	2,244	2,298	2,384
Zone 3 (Valley Region)	6,418	6,513	6,590	6,671	6,922
Zone 4 (East Bay Region)	6,989	7,067	7,161	7,256	7,529
Zone 5 (San Francisco Region)	3,523	3,546	3,574	3,603	3,738
PG&E Service Area Total	19,845	20,096	20,364	20,632	21,407
Northern California Power Agency	510	517	524	531	551
Silicon Valley Power	474	480	486	491	510
Other Publicly Owned Utilities	203	204	206	207	210
Dept of Water Resources - North	375	375	375	375	375
PG&E Area Total	21,406	21,671	21,954	22,236	23,053

Source: California Energy Commission

Figure 7 shows 2006 through 2008 summer daily peak demands and temperatures. Using 2008 loads and temperatures, staff estimates 1-in-2 demand at 21,200 MW compared to 21,671 MW in the *2007 IEPR* forecast. This implies 5 percent cumulative growth by 2010 to reach the *2007 IEPR* forecast of 22,236 MW. While this is higher than the 3.6 percent projected growth in economic output for the PG&E area, it is consistent with demand growth in previous recovery periods. Therefore, staff recommends no change to the PG&E area forecast.

Figure 7: PG&E TAC Area Daily Peak Demand Versus Temperature



Source: California Energy Commission

CDWR North

The CDWR North forecast represents CDWR pumping loads in the PG&E TAC area. The *2007 IEPR* forecast for CDWR North pumping load, based on average noncoincident summer afternoon peak, is 375 MW. As was done for CDWR South, staff recalculated the forecast based on a system coincident peak approach. In 2007, the coincident peak was about 270 MW. However, this includes the effects of up to 200 MW of demand response which may be counted towards resource adequacy requirements, both system and local. Therefore, staff recommends no change to the CDWR North forecast at this time.

Revised SCE Area Forecast for 2010

The LCR study uses a 1-in-10 demand forecast, meaning forecasted demand at annual maximum temperatures at the 90th percentile. To recalculate the 2010 SCE area forecast, staff used the *2007 IEPR* forecast of 2009 peak demand under 1-in-2 temperatures for each LSE with retail customers. For CDWR South the coincident peak forecast discussed earlier is used. To this revised 1-in-2 forecast, the 1-in-10 scalars developed as part of the *2007 IEPR* forecast are applied. These scalars represent the expected percentage increase in demand as temperatures rise from 1-in-2 to 1-in-10 levels. The SCE area scalar was applied proportionately to climate zones within the SCE service area based on the temperature responsiveness estimated from California ISO inland and coastal hourly load data.

Table 4 shows the revised SCE area forecast. The revised 1-in-2 peak demand forecast of 24,152 MW is almost 700 MW, or 2.8 percent, lower than the ***2007 IEPR*** forecast. The revised 1-in-10 forecast is 7.776 percent higher than the 1-in-2, using the same temperature response scalar as in the ***2007 IEPR***. No changes were made to the forecasts for PG&E, SDG&E, or other areas.

Table 4: Revised Forecast for SCE Area 2010 Peak Demand (MW)

	***2007 IEPR* Forecast**		**Revised Forecast**		
	1-in-2	**1-in-10**	**1-in-2**	**1-in-2**	**1-in-10**
Coincident Peak by Utility	**2010**	**2010**	**2009**	**2010**	**2010**
SCE Service Area by Climate Zone:					
Zone 7 (Southern San Joaquin Valley)	1,318	1,417	1,264	1,292	1,387
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Source: California Energy Commission